Memorandum

TO: James Mundt, Director
Office of Fiscal and Management Analysis, Legislative Services Agency

FROM: Janet McCabe, Assistant Commissioner
Office of Air Management

DATE: June 15, 2000

SUBJECT: Comparison Summary of the Estimated Economic Analysis of Fiscal Impact of New Rules Concerning Emissions of Nitrogen Oxides: LSA #98-235

The Department of Environmental Management (IDEM), on February 28, 2000 submitted the following for your economic impact analysis:

1. The draft rule published February 1, 2000 in the Indiana Register.
2. The estimated economic impact of the February 1, 2000 draft rule.
3. The fiscal impact memo submitted to the State Budget Agency.

In response to comments received from the Second Notice of Comment Period published February 1, 2000, comments received on the fiscal impact analysis submitted to the Legislative Services Agency on February 28, 2000, and IDEM policy decisions, the draft rule has been revised to present to the air pollution control board on August 2, 2000. IDEM is submitting this revised rule for your economic impact analysis under IC 4-22-2-28, IC 13-14-9-5, and IC 13-14-9-6. The following information is provided for your analysis:

Attachment 1. The revised rule (June 1, 2000) to be presented to the air pollution control board on August 2, 2000.
Attachment 2. Revised fiscal impact analysis based on the revised rule and comments received.
Attachment 3. The fiscal impact memo submitted to the State Budget Agency.
Attachment 4. “The Projected Impact of NOx Emissions Reductions on Electricity Prices in Indiana”, State Utility Forecasting Group, Purdue University.

Changes based on revisions to the draft rule published with the Second Notice of Comment Period

The changes to the rule significantly affecting the cost analysis are:

- ! Revised emissions monitoring requirements for electricity generating units (EGUS).
- ! Revised emissions monitoring requirements for industrial, commercial, and institutional units (ICI).

Each of these changes has the effect of reducing the anticipated costs of the rule to affected sources.

The draft rule published with the Second Notice of Comment Period required that all the affected units monitor their nitrogen oxide (NOx) emissions using continuous emissions monitoring systems (CEMS). This rule provision required a need for fifteen (15) additional CEMS for EGUS and thirty-six (36) CEMS for ICIs. It was estimated that this requirement would cost $2.7 million in startup costs and $563,000 in annual costs to EGUS and $6.5 million to $7.1 million in startup costs and $1.3 million to $1.5 million in annual costs to ICIs. Based on review of comments on this provision and review of other state and federal monitoring requirements, the department has determined that the emissions from certain low emitting units can be monitored with reasonable accuracy with less expensive alternative procedures that are based on tracking process operations. Therefore, the rule has been revised to allow these units the options to monitor their emissions using CEMS or using alternative procedures. With the revised provision, the sources may use alternative procedures to monitor emissions from oil or gas fired turbines and ICI units. The fiscal economic impact analysis has been revised to assume three additional CEMS on ICI units. Since monitoring operating conditions is a part of the normal operating practice, no impact due to alternative monitoring procedures has been assumed.

On January 18, 2000, U. S. EPA published a final rule in the Federal Register finding that certain EGUS and ICIs located in Indiana contribute to the non-attainment and interfere with the maintenance of 1-hour ozone ambient air quality standards in the states of New York and Connecticut. Using the authority provided to it by Section 126 of the 1990 Clean Air Act Amendments to prevent emissions from one state interfering with the attainment and maintenance of air quality standards in another state, EPA published emissions standards and other requirements for these units. The emission standards include allowances, tons of NOx allowed to be emitted, for each unit under a federally administered cap and emissions trading program. Although U. S. EPA's findings are now the subject of a legal challenge, which may not be resolved for some time, the department received comments that in order to avoid ambiguity the state NOx rule should exclude these units. The department has concurred and has included a provision in the revised rule to exclude these units from the requirements of Indiana's rule if and when all legal challenges are resolved and the Section 126 requirements become final and effective. However, no adjustment has been made to the fiscal impact because of the pending legal challenges.

The Section 126 rule affects EGUS at the following five Indiana utilities: American Electric Power (four coal-fired units at Tanners Creek facility); Indiana Municipal Power Agency (combustion turbines at Anderson and Richmond facilities); Indiana Kentucky Electric (six coal-fired units at Cliffty Creek facility); Cinergy (2 combustion turbines at Connersville facility, four coal-fired units at Gallagher facility, three coal-fired units at Noblesville facility); and Richmond Power & Light (two coal-fired units). The rule lists ICIs at the following three sources: Michelin North America, Superior Laminating, and the Dalton Foundries. The department has requested EPA to exclude these units from the list as they do not satisfy its criteria for large ICIs. These units were not included in the fiscal economic impact analysis therefore the Section 126 exclusion provision in the rule does not affect ICI costs.

Changes to the February 28, 2000 fiscal impact analysis based on comments received

Two utilities provided comment on the February 28, 2000 fiscal impact analysis. Based on comments and the agency's review of certain assumptions concerning, variable operation and maintenance costs for selective catalytic reduction (SCR), IDEM has made several changes to address these. The comments were related to averaging emissions of sources across the state, control of sources that directly contribute to areas that are classified as nonattainment, cost estimation procedures and the estimated specific costs. On the procedural aspects, the comments include expressing costs in 2007 dollars instead of 1998 dollars. The Department believes that expressing costs in 1998 dollars introduces a greater degree of accuracy as there are a number of unknowns in expressing costs in 2007 dollars, such as, speed of utility deregulation, uncertainty in economic factors, development in NOx control technologies, and other state and federal NOx control programs.

IDEM has revised scenario #3 and #4 in Table 1, Utility NOx Control Costs Summary, based on acceptable source specific information provided by one utility. In addition, the department found that certain control operating cost parameters used for some utilities in the analysis were low and has replaced them with values based on estimates provided by other utilities. These changes are incorporated into the revised fiscal impact analysis based on the draft rule to be submitted to the air pollution control board on August 2, 2000.

Impact on electricity rates

In addition to estimating the cost of the draft rule on affected sources, IDEM has obtained an analysis of the potential impacts of the rule on electricity prices. The State Utility Forecasting Group (SUFG) located at Purdue University in West Lafayette, Indiana, using a regulation forecasting model, has estimated the impacts of NOx control on electricity prices corresponding to an emission level equal to 0.25 lb/mmBtu (as required by the draft rule) and 0.15 lb/mmBtu (as required by the NOx SIP call by EPA). The forecasting model projects electric energy sales and peak demands as well as future electric rates given a set of exogenous factors describing the future of Indiana economy and prices of fuels. The analysis included five investor owned utilities and three major not for profit entities that supply electric power to Indiana customers. The model used the estimated costs for the four (4) scenarios, described in the analysis, corresponding to 0.25 lb/mmBtu level and the estimated cost corresponding to a 0.15 emission level using the emissions and cost data in scenario #3. For more details, please refer to the attachment "The Projected Impacts of NOx Emissions Reductions on Electricity Prices in Indiana", State Utility Forecasting Group, Purdue University. An increase in the electricity rates equal to 4% to

6% corresponding to 0.25 mmBtu emission level and 6% to 8% corresponding to 0.15 lb/mmBtu emission level from the unchanged emissions levels is predicted. It must be noted that a difference equal to 75% ($428 million) in the installation cost among the four scenarios corresponding to the 0.25 emission level has not shown a significant difference in the projected rate increases.

Summary

The revisions from comments on the fiscal impact analysis, changes in assumptions, and changes in the emissions monitoring requirements, result in an eight percent (8%) lower overall cost effectiveness (dollars per ton of NOx removed). Attached is a table comparing the analysis changed due to comments on the February 28, 2000 version and the analysis based on the revised draft rule to be presented to the air pollution control board on August 2, 2000.